The California Energy Crisis: Implications for Electricity Market Restructuring

Insufficient electricity supply, transmission constraints, limited natural gas supplies, heat waves, and prolonged drought in the West that greatly restricted hydroelectricity supplies contributed to blackouts and brownouts in California in 2001, huge electricity price spikes throughout the West, and the bankruptcy and near bankruptcy of California's largest utilities. Many are blaming California's attempt at deregulating the electricity industry as a major contributing factor to California's energy woes. The resulting political fallout, as well as a genuine need to take a closer look at their markets, has caused those States that have not restructured their electricity markets to scale back efforts toward that goal. Some States that have passed, but not yet implemented, restructuring legislation have postponed implementation dates.

On September 20, 2001, California abandoned its retail choice program altogether. Proponents for regulation and proponents for competition in the electricity industry are gathering evidence from the California crisis to support their positions in a debate that has been ongoing since the first power companies were formed.

Arguments For and Against Competition in Electricity Markets

A basic tenet of market economics is that true competition will afford customers the lowest prices and best service possible and will spur technology development that will create even lower prices and better services. In order for a market to come close to true competition, supply and demand must be able to respond quickly to each other through price signals. Each supplier has a minimum acceptable price to supply a given amount of commodity or service, and each customer has a maximum acceptable price to acquire a certain quantity of good. In a perfectly competitive market, where there are many buyers and sellers, the prices and quantities of products supplied and bought are determined by the level at which the marginal cost to produce the product [*25*] equals the marginal benefits to consumers [*26*]. When there is a shortage of a product with no or few substitutes the equilibrium price will rise. When more resources are introduced into the market or affordable substitutes become available, the equilibrium price will fall.

Advocates for and against a competitive electricity market generally agree that reliable electricity at reasonable prices is vital to maintaining the health and welfare of the economy and the public at large. Those who support regulation believe that events in California illustrate that system reliability and price stability cannot be incorporated into a competitive system. In their opinion, it is not in the interest of suppliers to hold or build more generation than they are certain they can sell. Therefore, in situations of unexpected demand increases, system reliability will be compromised.

Proponents of regulation also believe that supply cannot be built nor shut off fast enough to respond to demand in an economically feasible way [*27*]. Therefore, they assert, the resulting price spikes in times of unexpected high demand will persist for the long period of time needed for supply to adjust; and thus, a competitive market cannot guarantee stable or affordable electricity prices for all. They contend that the resulting system unreliability and price instability can damage the health and vitality of the nation, citing the amount of money lost by businesses during the California blackouts, the danger of electricity surges and outages to people at home dependent on life-support systems, and the deaths of people without power during extreme weather conditions.

Competition advocates believe that competition ultimately will produce lower electricity prices and better services as competitive suppliers seek to increase and retain a customer base. For instance, technically it now takes as little as 18 months to build new natural-gas-fired combined-cycle plants. Competition advocates also assert that more than ever, there are reasonably priced distributed generation alternatives to grid-based generation, such as reciprocating engines and gas combustion and microturbine units [*28*]. Additionally, there are energy management options to lower energy usage as needed in times of scarcity and price increases as well as during the most expensive peak periods.

Supporters of competition believe that a market that is set up properly will encourage efficiency and technological developments that will increase the responsiveness of market demand and supply to price signals by increasing the availability of affordable substitutes to grid generation, by increasing the ease of demand response to price (for example, through use of the internet), and by encouraging improved electricity transmission infrastructure through price signals. They contrast California's market design to restructured market designs in other States or regions that have been performing much better.

California's Restructured Market Design

The Retail Market

California was one of the first States to restructure its retail electric power markets. In 1996 (when California passed deregulation legislation), the average price of electricity in California was 9.48 cents per kilowatthour, the 10th highest among the 50 States and the District of Columbia. The U.S. average price was 6.86 cents per kilowatthour. Under California's restructuring plan, which started on March 31, 1998, customers of California's three investor-owned utilities (IOUs) were allowed to shop for alternative sources of power. The IOUs were allowed to recover investments (stranded costs) made with the approval or mandate of their regulator—the California Public Utilities Commission (CPUC)—that they would not be able to recover within the new competitive market structure [*29*]. Regulators assumed there would be a period of transition until the market became truly competitive and these stranded costs would be paid off.

Regulators also assumed that prices would be lower under a competitive market structure, with the need to retain and win customers producing incentives to provide electricity at lower cost. Operating under this assumption, legislators froze electricity prices for IOU customers at June 1996 levels and mandated a 10-percent rate reduction for residential and small commercial customers for the transition period so that customers would see immediate benefits of the new market, even with the stranded costs they were paying [*30*]. To protect customers during the transition period, utilities were required to supply electricity to all default customers—customers who did not want, or were not given the opportunity, to switch to a competitive supplier—as well as to serve as the suppliers of last resort for customers who were dropped or abandoned by their competitive suppliers.

The Wholesale Market

As California attempted to create a competitive supply market, regulators required utilities to divest most of their generation assets and buy power through a Power Exchange (PX) at spot market prices. Consequently, the percentage of IOU ownership of generating capacity in the State of California dropped from 55 percent to 15 percent after the implementation of competition in 1998 [*31*]. The nonutility share of generating assets increased from 19 percent to 54 percent after competition was implemented [*32*]. (The remaining third of California's generating assets are owned by public utilities).

In addition to the energy needed to power machinery and appliances, electricity generators also must provide extra power, such as reactive power needed to balance the electricity system, as well as reserves in case more than expected energy or reactive power is needed. California was the only State that set up separate markets for energy and for the "extra" power needed to provide transmission operating and reliability services. Until recently, the PX operated multiple energy markets, the most important of which were the day-ahead and hour-ahead markets. The California Independent Systems Operator (CAISO) operates multiple transmission product markets for the different types of capacity reserves and ancillary services (spinning and non-spinning reserves, regulation, etc.) needed to keep the transmission system operating reliably on a day-ahead, hourly, and real-time basis. CAISO also dispatches power plants and operates the transmission grid. If adequate bids are not received, CAISO can offer above-market (out-of-market) prices to obtain sufficient resources. If above-market prices still fail to garner sufficient resources, emergency measures are triggered, resulting in Stage 1-3 alerts [*33*, *34*].

Problems with California's Market Design

Design flaws in California's competitive electricity market have surfaced throughout its short history. For one, although a substantial $89 million customer education campaign was launched, it was hard to persuade unregulated retail competitors to enter and stay in the market. Only a small percentage of customers left utility suppliers (Figure 8). With utilities forced to sell at low rates and customers making high payments for stranded costs on the distribution portion of their bills (regardless of the generation supplier), it was difficult for competitive suppliers to offer rates low enough to provide the incentive needed to persuade consumers to risk switching to unfamiliar retail electricity companies.

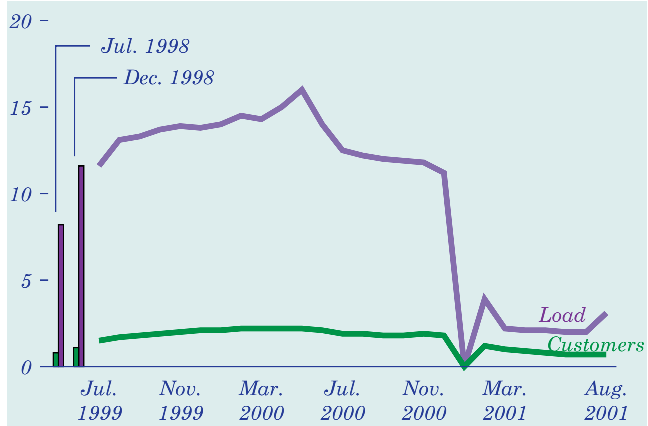
In contrast, Pennsylvania—which provided more room between utility and competitive rates through "shopping credits" [*35*]—has seen up to 24 percent of its electricity load switch to competitive suppliers. Maine, which allowed competitive suppliers to bid for default customers, has seen up to 35 percent of its load switch to competitive suppliers. Recently, Pennsylvania has also opened its default customer load to competitive bids.

Most of the customers in California who chose competitive suppliers did so to support the emerging "green energy" market. Although green energy prices were higher than other electricity products, the California Energy Commission (CEC) offered a renewable energy customer credit ranging from 1.5 cents per kilowatthour at the start of retail choice to 1 cent per kilowatthour by the end. The proportion of customers receiving the credit relative to total direct access customers increased steadily to the point where those purchasing renewable energy comprised nearly all of the direct access market. By June 2000, the total number of direct access customers in all customer classes had increased to 209,000, with 199,000 (95 percent) of them receiving the renewable energy customer credit. Virtually all residential direct access customers were receiving the customer credit by then [*36*].

Meanwhile, electricity demand in California started to rise more rapidly than had been predicted. From 1990 through 1999, overall electricity demand in California increased by 11.3 percent, largely as a result of rapid growth in the high-tech sector and population growth in the latter part of the decade [*37*]. Strong economic growth increased demand for energy in all customer classes. According to the CEC, this trend is expected to continue [*38*]. The CEC is projecting large increases in electricity demand through 2010 as a result of: (1) expected population growth of approximately 15 percent from 2000 to 2010; (2) stronger expected population growth in hotter inland areas (26 percent) than in coastal areas (11 percent), which is expected to lead to more demand for air conditioning, exacerbated by an increase in telecommuting; and (3) a standard of living fueled by high-tech industries, which demand a resilient electricity system that provides reliable and high-quality power [*39*].

While electricity demand increased in California, net generating capacity decreased by 1.7 percent from 1990 to 1999 [*40*]. Consequently, the State's reliance on power imports increased. California currently relies on about 11,000 megawatts of out-of-State capacity [*41*]. However, demand has also been increasing more rapidly than expected in neighboring States. Census Bureau figures show that, in the past 10 years, Washington, Oregon, Arizona, and Nevada have been rapidly growing in population [*42*]. Unsure of receiving adequate compensation under the emerging competitive structure, California's utilities took no action to build new plants. Long and expensive siting and permitting procedures to build new generation, several years of high water levels—yielding an abundance of cheap hydroelectric imports—and low price caps on wholesale energy (before 2001) also discouraged new capacity additions.

Figure 8. Direct access customers in California's retail electricity market, 1998-2001 (percent of total)



Other regions—including States in the Northeast Power Coordinating Council, the Mid-Atlantic Area Council, and Texas—have faced similar demand increases but have been much more successful in promoting new capacity additions and expansions. Simpler siting and permitting procedures, higher or no price caps, and other regulatory procedures in place in each State and region have influenced how much needed capacity has been or is being built.

Price spikes hit California's wholesale markets in the first year of operation. In the summer of 1998, the California ISO experienced price spikes and bid insufficiencies in its newly established ancillary services markets. As a result, the Federal Energy Regulatory Commission (FERC) approved a purchase price cap for those markets. Stressing that the cap was not to remain in place for long, FERC directed the ISO to facilitate a comprehensive stakeholder process to redesign the ancillary services markets and to file a redesign proposal no later than March 1, 1999. In general, however, during the first 3 years of operation, a convergence of favorable fuel prices, temperatures and hydropower conditions resulted in such low spot market prices that the IOUs were able to write off substantial amounts of stranded costs.

By 2000, extreme winter and summer weather conditions created sudden high peaks in energy demand. At the same time, the West was experiencing a drought, reducing the amount of water available for hydroelectric power generation. To make matters worse, producers of natural gas, which fuels roughly one-half of California's electricity generators, had been curtailing production in response to all-time low prices [*43*]. Extreme wholesale price spikes resulted as peak demand surpassed available supply. Older plants, called on to run more than usual, caused California to surpass emissions standards. The high costs of meeting California's power plant emissions requirements also contributed to the increase in wholesale electricity prices [*44*]. Additionally, overuse of older plants caused them to break down, further exacerbating the supply problem.

As electricity supply tightened, problems with the design of California's wholesale electricity market structure came to light. A major problem was the two-tiered structure of California's energy and ancillary service markets. Because both markets require generators to provide or set aside the same amount of output regardless of which product or service the output is providing, power suppliers naturally bid into the market that offered the opportunity to receive the highest prices. A strict balance must be maintained between all the electricity services to maintain a reliable system. Thus, mass migration to one market will cause prices in the other markets to rise. The CAISO was often forced to buy electricity at out-of-market prices in order to balance and maintain a reliable energy flow.

Another problem cropped up with California's congestion management system [*45*]. Congestion charges were averaged over zones instead of being charged to generators according to the actual cost of the congestion they caused. The CAISO contended that this promoted "gaming" of the congestion system, because generators with market power on the export side of a constraint could overschedule in the day-ahead market and then submit very low or negative decremental bids to alleviate the congestion it created. Generators thus created artificial scarcity in order to create congestion revenues that would be paid to them [*46*].

Critics asserted that when pricing does not conform to the operating conditions, substantial operating restrictions must be imposed to preserve system reliability. Customer flexibility and choice require efficient pricing; inefficient pricing necessarily limits market flexibility [*47*]. In California's case, however, the CAISO had an even tougher job trying to maintain system reliability and control congestion by coordinating the two markets in the two-tiered market structure as suppliers jumped among the markets. In January 2000, the FERC called for an overhaul or replacement of California's congestion management approach.

A series of price caps, implemented in lieu of effective market controls, dampened hourly price spikes but may have contributed to an increase in average prices. Throughout the summer of 2000, an investigation by FERC staff [*48*] found that specific decreases in the CAISO price cap led to increased exports from California to other areas within the Western Systems Coordinating Council (WSCC), which operates the Western grid. Overall, this may have led to higher average prices as energy supplies within California became even more constrained.

Transmission constraints between northern and southern California topped off the bad situation, resulting in rolling blackouts and brownouts as well as substantial wholesale price spikes that continued well into 2001. With such high prices, most of the competitive retail suppliers left the market, and their customers defaulted to the utilities (Figures 9 and 10). The requirement to buy generation through the PX had hindered California's IOUs from hedging against volatile spot market prices by entering into bilateral contracts with generators. Because the IOUs were not allowed to pass on the huge costs of wholesale power, which on average were 8 times higher than prices at the start of competition in 1998, they lost billions of dollars and their credit ratings.

The governor and the CPUC concluded that suppliers were exercising market power by playing one tier of the market against the other. They urged the FERC to exercise control over suppliers and order them to return the billions of dollars lost by the utilities. In March 2001, the FERC ordered public utility power suppliers to reimburse the CAISO and the PX $69 million for January 2001 overcharges. The utilities, to date, have not been compensated for the large losses they experienced. California's largest utility, Pacific Gas and Electric, filed for Chapter 11 bankruptcy protection in April 2001. Southern California Edison, the second largest utility, was teetering on the edge of declaring bankruptcy but reached an agreement with the State in October 2001 to allow it to pay off its debts by significantly raising rates for the next 2 years.

From November 2000 through 2001, the FERC ordered remedies for California's wholesale power markets. Among other things, the FERC ordered the elimination of the mandatory requirement that the three IOUs sell and buy all their power through the California PX. The FERC also terminated the wholesale rate schedule that enabled the PX to continue operating, and in January 2001 the PX ceased operations [*49*]. Congestion management procedures and pricing were ordered to be redesigned, demand response procedures were to be considered, and market monitoring procedures were to be strengthened.

Re-Regulation

California's governor, regulators, and legislators, under pressure from the State's utilities and consumers, have not been willing to wait and see whether a FERC-ordered market redesign will allow the market to function satisfactorily. With the IOUs unable to recover the high costs of wholesale power through reimbursements from customers, suppliers, or the government, they were unable to make payments on much of their power purchases, and power generators refused to sell them more power. As a result, the State took over the job of buying power. On February 1, 2001, the California Department of Water Resources (DWR) was authorized to buy power for the utilities.

The DWR negotiated long-term contracts, many through 2010 and some through 2020, for more than one-half of California's projected energy needs through 2010. Although the long-term contracts have stabilized prices, they were negotiated at much higher average costs than are projected for the State's spot market.

The California legislature has guaranteed the DWR reimbursement of the revenue requirements for its electricity purchases through large ratepayer surcharges (increasing electricity prices by up to 46 percent for some consumers) and bond issues. In addition, the PUC formally ended California's retail access program, in order to ensure that the costs to the DWR would be shared by the roughly three-quarters of California's electricity load located within the jurisdiction of the three IOUs. These actions are expected to keep California's electricity prices from falling to the levels anticipated in its initial effort at deregulation.

In May 2001, Governor Gray Davis signed a bill creating the California Consumer Power and Conservation Financing Authority, which will have broad powers to construct, own, and operate electric power facilities and finance energy conservation projects. He also signed an emergency bill to shorten the times for reviewing applications for new and upgraded power plants. The bill also allows new owners to pay emission mitigation fees in lieu of obtaining emission offsets when such offsets are unavailable.

Implications of the Failure of California's Experiment with Competition

The failure of California to maintain a workable competitive electricity market has highlighted the difficulties of designing a competitive electricity market structure that works. The political need to ensure consumers short-term benefits, in the form of lower prices, may inhibit formation of market designs that would create cheaper electricity, better service, and a cleaner environment in the long term.

Figure 9. Direct access customer load in California's retail electricity market, 1998-2000 (percent of total)

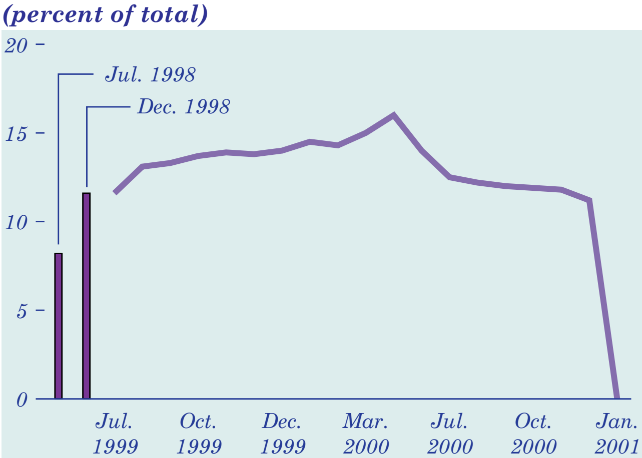
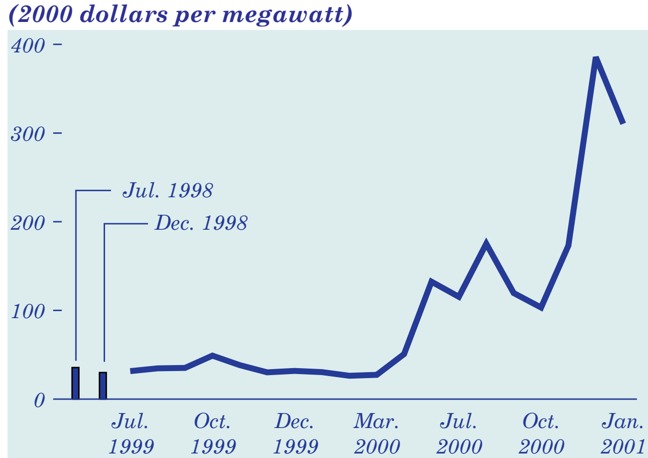


Figure 10. California's Power Exchange (PX) energy price, 1998-2000 (2000 dollars per megawatt)



It may be too early to judge whether competition will work better than regulation in other regions. So far, some other regions faced with the same challenges as California have been more successful in changing regulations, implementing transmission improvements, and redesigning market infrastructure when necessary. The FERC has approved market design changes for the PJM, New England, and New York ISOs as they work to improve transmission service and the functioning of their wholesale markets. In addition, various States have revised restructuring legislation to make the retail electricity market more competitive by streamlining plant siting and construction procedures, allowing competitive suppliers to bid for default customers, and adjusting shopping credits, among other changes.

ISOs, States, and competitive suppliers are currently looking into improving demand response options, including procedures for adding advanced metering devices and services, incorporating net metering regulations for customers who generate their own electricity, making it easier to connect distributed generators to the grid, and offering energy management services. Some States have pushed back retail competition start dates until supply is deemed adequate to forestall the threat of market power abuse by a few suppliers.

Under Order No. 2000, issued in December 1999, the FERC called for the voluntary formation of Regional Transmission Organizations (RTOs), stating that RTOs would broaden the market for electric power transactions and help ensure comparability of service for users, reliability for consumers, and efficient economic transactions for customers. The FERC has recently become more adamant in its encouragement of the formation of large RTOs—as few in number as possible in order to improve market performance—with a stated preference for one Western RTO consisting of all the States connected to the Western grid. Aware that the failure of competition in California could dampen support for competition, and under pressure to formulate stricter guidelines for RTO formation [*50*], FERC Chairman Pat Wood has stated his intention to formulate protocols for the RTO organizations, beginning with a series of Commissioner-led workshops in mid-October 2001 on the core subject areas (congestion management, cost recovery, market monitoring, transmission planning, business and reliability standards, nature of transmission rights, etc.) [*51*].

The Role of Natural Gas Prices

Natural-gas-fired generating plants provide approximately one-half of California's electricity. In the State's competitive wholesale market, the electricity price for a given period represents the price paid to the last generator dispatched to the grid. Because petroleum- and natural-gas-fired generators usually have higher fuel costs than hydroelectric, nuclear, or coal-fired generators, petroleum and natural gas units are typically dispatched last to serve intermediate and peak loads. Thus, gas-fired generators often set the wholesale electricity price, and the cost of the natural gas used for electricity generation plays an important role in determining California's wholesale electricity prices.

Natural gas wellhead prices increased significantly during the second half of 2000, after drilling was curtailed in response to low prices in 1998 and 1999. Because there is a 6- to 18-month lag between increased drilling investments and natural gas production increases, producers could not respond to California's sudden demand for natural gas for electricity generation. The resulting supply shortage led to higher natural gas prices, which coincided with California's electricity supply problems and subsequent increases in wholesale electricity prices. Some have blamed the high natural gas prices on high electricity prices; others have noted the contribution of high natural gas prices to high electricity prices. After September 2000, the delivered price of natural gas in California became decoupled from those elsewhere in North America.

California typically relies on out-of-State sources to supply approximately 83 percent of the natural gas it consumes. Reliance on out-of-State supplies has integrated California into the North American natural gas market through gas transmission facilities, which bring supplies into California from Canada, Wyoming, New Mexico, and Texas. The extensive North American transmission system works to equilibrate natural gas prices across the continent, with differences in regional wholesale prices largely attributable to the regional availability of spare transmission capacity and the cost of transporting gas from one region to another.

California's relationship to the North American supply market is quantified by the price differential between the prices for natural gas delivered to California and the spot prices posted at the Henry Hub in

Louisiana. The Henry Hub is the largest and most prominent "market center" for natural gas in North America [*52*]. The NYMEX futures trading contract specifies the Henry Hub as that contract's physical delivery point, because this market center provides the most flexibility to buyers and sellers in terms of transmission receipt and delivery points. Consequently, the Henry Hub spot price best reflects the overall supply and demand situation for the North American natural gas market.

A comparison of Henry Hub spot prices and delivered prices to California electric utilities shows that the annual price differential varied between approximately 40 and 70 cents per thousand cubic feet from 1997 through 1999. As natural gas prices at the Henry Hub rose during 2000, so too did the price of gas delivered to California utilities. During the first half of 2000, the price differential between the Henry Hub price and the delivered California price stayed within the bounds of the historic price differentials. In the latter part of the year, however, the difference between the Henry Hub price and delivered California gas price increased substantially. By December 2000 the average monthly price difference was over $10.00 per thousand cubic feet, and on some days the differences were much larger.

The huge price disparity between delivered California gas prices and the Henry Hub spot prices can only be explained by supply and demand conditions unique to California. In the neighboring States of Arizona and Nevada there was no significant divergence from historical patterns. Something unique occurred in the California market that caused natural gas prices in the State to become decoupled from the North American natural gas market.

The principal reason for the skewing of California's natural gas prices was a lack of sufficient pipeline capacity in the State. As noted above, about 83 percent of the natural gas consumed in California is transported from outside the State. Insufficient transmission capacity to move natural gas from the California border caused prices in California to rise well above those in the rest of the U.S. natural gas market.

Temporary constraints on interstate pipelines delivering natural gas into California also appear to have played a role in raising the price of natural gas in the State. For example, on August 19, 2000, there was a rupture in the El Paso Pipeline outside Carlsbad, New Mexico, reducing gas transmission capacity throughout the remainder of the 2000-2001 winter season. The damaged pipeline segment was carrying 1.2 billion cubic feet per day at the time of the rupture. After the rupture, the Henry Hub/California price differentials for September and October rose to 86 cents per thousand cubic feet and 94 cents per thousand cubic feet, respectively, from 38 cents per thousand cubic feet in August.

Interstate transmission capacity to deliver natural gas at the California border exceeds the "take-away capacity" of California's intrastate pipeline system by approximately 300 to 590 million cubic feet per day. Inadequate pipeline capacity constrained gas supplies from entering California and moderating delivered gas prices to a level more commensurate with historical price differentials.

California electricity and natural gas prices reached unusually high levels as a result of rigidities in both markets, which impeded market efforts to bring supply and demand into balance. In the electricity market, fixed retail prices prevented the consumption adjustments necessary to mitigate the deficit of hydroelectric generation and the lack of sufficient transmission capacity. In the natural gas market, inadequate transmission capacity impeded market efforts to increase gas supplies in response to the greater demand for natural gas resulting from the electricity market's attempts to substitute natural-gas-fired generation for inadequate hydroelectric generation. If either of these market rigidities had not been present, it is likely that prices would not have reached the unusually high levels they did.

Changes in the AEO2002 Forecast for Electricity Prices in the California Region

The National Energy Modeling System (NEMS) has been modified to take into consideration the prices of long-term power contracts for projections of electricity prices for the California region, as well as the fact that competition in the retail market has been terminated. As a result, the *AEO2002* projected electricity prices in California are higher than the *AEO2001* projected prices through the end of the forecast period [*53*]. In the *AEO2001* forecast, California electricity prices reached a projected high of 10.6 cents per kilowatthour in 2000, fell to a low of 7.0 cents per kilowatthour in 2012, and rose slightly to 7.3 cents per kilowatthour by 2020 [*54*]. In the *AEO2002* forecast, average electricity prices in California are projected to reach a high of 13.5 cents per kilowatthour in 2001—a direct result of the surcharge imposed by recent State legislation, as described above—but are expected to decline as the average long-term contract price declines and the amount of generation bought on the spot market increases. Prices are expected to be 8.8 cents per kilowatthour in 2020, 1.5 cents per kilowatthour higher than projected in *AEO2001*, as a result of changes in California's market structure.

Phasing Out MTBE in Gasoline

Methyl tertiary butyl ether (MTBE) is widely used as a blending component in motor gasoline, accounting for about 3 percent of the total volume of gasoline sold in the United States in 2000. Initially, MTBE was added to gasoline to boost octane, which helps prevent engine knock. Then, in the 1990s, it began to be used to meet the 2-percent oxygen requirement for reformulated gasoline (RFG). The Clean Air Act Amendments of 1990 (CAAA90) require RFG to be used year-round in cities with the worst smog problems. In the past few years, the use of MTBE has become a source of debate, because the chemical has made its way from leaking pipelines and storage tanks into water supplies throughout the country. Concerns for water quality have led to a flurry of legislative and regulatory actions at both the State and Federal levels.

MTBE is an important blending component for RFG because it adds oxygen, extends the volume of the gasoline, and boosts octane, all at the same time. In order to meet the 2-percent (by weight) oxygen requirement for Federal RFG, MTBE is blended at approximately 11 percent by volume, thus extending the volume of the gasoline. When MTBE is added to a gasoline blend pool, it has an important dilution effect, reducing the fraction of undesirable compounds such as benzene and aromatics. The dilution effect is even more valuable in light of a ruling by the U.S. Environmental Protection Agency (EPA) that will require the sulfur content of gasoline to be reduced substantially by 2004 and its Mobile Source Air Toxics (MSAT) regulatory program, which will maintain benzene at 1998-2000 levels (see "Legislation and Regulations"). In addition, MTBE is a valuable octane enhancer. Its high octane helps offset the Federal limitations on other high-octane components, such as aromatics and benzene. If the use of MTBE is reduced or banned, refiners must find other measures to maintain the octane level of gasoline and still meet all Federal requirements.

MTBE is the oxygenate that is used in almost all RFG outside of the Midwest. Ethanol, which is currently used in the Midwest as an oxygenate in RFG and as an octane booster and volume extender in traditional gasoline, would be the leading candidate to replace MTBE. Even without the Federal oxygen requirement on RFG, refiners would need to make up for the loss of volume and octane resulting from a ban on MTBE. Reliance on other oxygenates, including ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME), is assumed to be limited because of concerns that they have many of the same characteristics as MTBE and may lead to similar problems that affect the water supply.

Ethanol currently receives a Federal excise tax exemption of 53 cents per gallon, which is scheduled to decline to 52 cents in 2003 and 51 cents in 2005. Legal authority for the Federal tax exemption expires in 2007, but because the exemption has been renewed several times since it was initiated in 1978, the *AEO2002* reference case assumes that it will be extended at the 51-cent (nominal) level through 2020. Blending with ethanol, which is primarily produced from corn, is also encouraged by tax incentives in 17 States to help bolster agricultural markets. Some of the characteristics of ethanol have made it less attractive to refiners than MTBE as an oxygenate. Ethanol results in higher emissions of smog-forming volatile organic compounds (VOCs) than MTBE. Its higher volatility makes it more difficult to meet emissions standards, especially in the summertime, when RFG must meet VOC emissions standards. Ethanol's volatility also limits the use of other gasoline components, such as pentane, which are highly volatile and must be removed from gasoline to balance the addition of ethanol.

In addition to being more volatile than MTBE, ethanol contains more oxygen. As a result, only about half as much ethanol is needed to produce the same oxygen level in gasoline that is provided by MTBE. The result is a volume loss, because the other half of the displaced MTBE volume must come from other petroleum-based gasoline components. Ethanol is slightly higher in octane than MTBE is, but because only one-half as much ethanol is blended, a net loss in octane occurs when ethanol is used to replace MTBE. Blending with ethanol also results in a slight increase in emissions of toxics, which must be compensated by other blending changes in order to comply with "antibacksliding" regulations.

The prospect of increased use of ethanol also poses some logistical problems. Unlike gasoline blended with MTBE and other ethers, gasoline blended with ethanol cannot be shipped in multi-fuel pipelines in the United States, because moisture in pipelines and storage tanks causes ethanol to separate from gasoline. When gasoline is blended with ethanol, the petroleum-based gasoline components are shipped separately to a terminal and then blended with the ethanol when the product is loaded into trucks. Thus, changes in the current fuel distribution infrastructure would be needed to accommodate growth in "terminal blending" of ethanol with gasoline. Alternatively, changes in pipeline and storage procedures would be needed to allow ethanol-blended gasoline to be transported from refineries to distributors.

Ethanol supply is another significant issue, because current ethanol production capacity would not be adequate to replace MTBE nationwide. At present, ethanol supplies come primarily from the Midwest, where most of it is produced from corn feedstocks. Shipments to the West Coast and elsewhere via rail have been estimated to cost an additional 14.6 to 18.7 cents per gallon for transportation [*55*]. If the demand for ethanol increased as a result of a ban on MTBE, higher prices could make new ethanol facilities economically viable, and sufficient capacity could be in place depending on the timing of the MTBE ban.

Because the *AEO2002* projections reflect only current laws and regulations, they incorporate MTBE restrictions in the States where they have been passed but do not include any proposed State or Federal actions. The *AEO2002* reference case assumes that the RFG oxygen requirement will be maintained and incorporates MTBE ban or reduction legislation that has been passed in 13 States: Arizona, California, Colorado, Connecticut, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington [*56*]. As a result, the amount of MTBE used by domestic refiners is projected to be cut in half by 2004, from 247 thousand barrels per day in 2000 to 123 thousand barrels per day. Nearly three-quarters of the projected decline in MTBE consumption results from a ban on MTBE in California, which is currently scheduled to begin at the end of 2002. The need to maintain oxygen and octane levels and to offset some of the volume loss associated with MTBE removal results in a projected national increase in ethanol blending of 60 thousand barrels per day in 2004 from the 2000 level of 106 thousand barrels per day.

Although 13 States have passed legislation to restrict the use of MTBE, growing concerns about the supply and price impacts of the restrictions have heightened uncertainty about when the laws will be enforced. The failure of California to obtain approval from the EPA for a waiver of the Federal 2-percent oxygen requirement in RFG has prompted discussions about delaying the MTBE ban because of concerns about the availability and price of ethanol in 2003, the first year of the State's scheduled ban on MTBE. The same concerns apply to other States that are scheduled to restrict MTBE.

On the other hand, the political impetus for more widespread restrictions on MTBE is evident. Numerous legislative proposals in the U.S. Congress have focused on an MTBE ban in all States [*57*]. Because of supply and price concerns, the ban is sometimes linked to a waiver of the oxygen requirement for RFG, which in turn is often linked to a renewable fuels mandate which would ensure that renewable fuels (ethanol) represent a certain percentage of the gasoline pool.

Although it was not possible to analyze all the variations of MTBE ban legislation that have been proposed, *AEO2002* includes a "Federal MTBE ban case" that can be considered the most severe scenario in terms of gasoline supply, because no oxygen waiver is assumed. This case was analyzed through 2010 and assumes that MTBE and other ethers cannot be blended into gasoline after 2005. In the Federal ban case it is projected that the remaining 118 to 128 thousand barrels per day of MTBE blended in gasoline between 2006 and 2010 would be eliminated, with an associated increase of 79 to 89 thousand barrels per day in ethanol consumption.

Previous analysis indicates that ethanol blending would increase even if the oxygen requirement on RFG were waived, because ethanol is a good option for replacing the volume and octane loss resulting from MTBE removal [*58*]. The extent to which ethanol would be used to replace octane and volume depends on the availability of other quality blendstocks, such as alkylate and iso-octane. As compared with the reference case projections, the national average pump price of gasoline is about 3 cents per gallon higher in the Federal ban case, with RFG prices 9 to 10 cents per gallon higher between 2006 and 2010. As a result of the higher prices, gasoline consumption between 2006 and 2010 is projected to be 60 to 80 thousand barrels per day lower in the Federal ban case than in the reference case.

The *AEO2002* projections are developed from a regional model, which captures the effects of limitations on MTBE in individual States through adjustments to assumptions about regional supplies of gasoline. The adjustments are made to reflect shifts in oxygenate selection and gasoline characteristics and changes in average gasoline prices in specific regions. Because the regional price changes are projected only on an annual basis, however, localized price spikes that might occur as a result of State MTBE bans are not reflected in the model results.

Multiple Emissions Controls in Electricity Markets

Background

Electric power plant operators may face new requirements to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) beyond the levels called for in current regulations. They could also face requirements to reduce carbon dioxide (CO_2) and mercury (Hg) emissions. At present neither the future reductions nor the timing for compliance is known for any of these airborne emissions. Given these uncertainties, compliance planning is difficult for plant owners.

Until recently, each of these environmental issues was addressed through separate regulatory programs, many of which are undergoing modification. To control acidification, CAAA90 required operators of electric power plants to reduce emissions of SO_2 and NO_x. Phase II of the SO_2 reduction program—lowering allowable SO_2 emissions to an annual national cap of 8.95 million tons—became effective on January 1, 2000 [*59*]. More stringent NO_x emissions reductions are required under various Federal and State laws taking effect from 1997 through 2004. For example, in 1997 the EPA issued new standards for particulate matter and ozone. The ozone standard was tightened from 0.12 parts per million measured over 1 hour to 0.08 parts per million measured over 8 hours. States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because electric power plant emissions of SO_2 and NO_x contribute to the formation of regional haze, States could require that these emissions be reduced to improve visibility in some areas. In the near future, it is expected that new national ambient air quality standards for ground-level ozone and fine particulates may necessitate additional reductions in NO_x and SO_2.

To reduce ozone formation, the EPA has promulgated a multi-State summer season cap on power plant NO_x emissions that will take effect in 2004. Emissions that lead to fine particles (less than 2.5 microns in diameter), their impacts on health, and the level of reductions that might be required are currently being studied. Fine particles are associated with power plant emissions of NO_x and SO_2, and further reductions in NO_x and SO_2 emissions could be required by as early as 2007 in order to reduce emissions of fine particles. In addition, the EPA decided in December 2000 that Hg emissions must be reduced; proposed regulations will be developed over the next 3 years, possibly as part of a multi-emissions reduction strategy. Further, if the United States decides that emissions of greenhouse gases need to be mitigated, it is likely that energy-related CO_2 emissions will also have to be reduced.

Because the timing and levels of emission reduction requirements under the new standards are uncertain, compliance planning is complicated. It can take several years to design, license, and construct new electric power plants and emission control equipment, which may then be in operation for 30 years or more. As a result, power plant operators must look into the future to evaluate the economics of new investment decisions.

The potential for new emissions standards with different timetables adds considerable uncertainty to investment planning decisions. An option that looks attractive to meet one set of SO_2 and NO_x standards may not be attractive if further reductions are required in a few years. Similarly, economical options for reducing SO_2 and NO_x today may not be the optimal choice in the future if Hg and CO_2 emissions must also be reduced.

Further complicating planning, some investments capture multiple emissions simultaneously, such as advanced flue gas desulfurization equipment that reduces SO_2 and Hg, making such investments more attractive under some circumstances. As a result, power plant owners currently are wary of making investments that may prove unwise a few years hence. Aware of these difficulties, both the previous and current Congresses have proposed legislation that would require simultaneous reductions of multiple emissions.

Congressional Requests

There have been three Congressional requests to the Energy Information Administration (EIA) for analyses of proposed legislation for reductions of multiple emissions. The Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform [*60*] asked EIA to “analyze the potential costs of various multi-emissions strategies to reduce the air emissions from electric power plants.” The Subcommittee requested that EIA examine cases with alternative NO_x, SO_2, CO_2, and

Hg emission reductions, with and without a renewable portfolio standard (RPS) requiring a specified portion of all electricity sales to come from generators that use nonhydroelectric renewable fuels.

In the cases specified by the Subcommittee, emissions of NO_x and SO_2 were to be reduced to 75 percent below 1997 levels beginning in 2002 and reaching compliance by 2008. CO_2 emissions were required to be reduced to 1990 levels by 2008 and 7 percent below 1990 levels by 2012. Hg emissions were to be reduced by 90 percent from 1997 levels by 2008. The RPS was targeted to reach 20 percent by 2020. The analysis examined the impacts of these requirements both for individual emissions and for all emissions taken together [*61*].

In a second study, requested by Senators Bob Smith, George Voinovich, and Sam Brownback, EIA was asked to examine the costs of different multi-emissions reduction strategies for NO_x, SO_2, and Hg. The Senators also requested an analysis of the potential costs of requiring power suppliers to acquire offsets for any increase in CO_2 emissions that occur beyond the level expected in 2008. The request called for 50- to 75-percent reductions in NO_x below 1997 levels, 50- to 75-percent reduction in SO_2 emissions below full implementation of CAAA90 Title IV, and 50- to 75-percent reductions in Hg emissions below 1999 levels, with half the reductions to be achieved by 2007 and the full reductions to occur by 2012. The emissions reduction programs, covering all electricity generators other than cogenerators producing both electricity and useful thermal output, were patterned after the SO_2 allowance program created in the CAAA90. One-half of the reductions in Hg emissions were to come from site-specific reductions [*62*].

A third analysis, requested by Senators James M. Jeffords and Joseph I. Lieberman, was to examine the potential impacts of limits on SO_2, NO_x, CO_2, and Hg emissions from electricity generators [*63*]. Using 2002 as a start date for emissions reductions, the request specified that, by 2007, NO_x emissions from electricity generators were to be reduced to 75 percent below 1997 levels, SO_2 emissions to 75 percent below the full implementation of the Phase II requirements under CAAA90 Title IV, Hg emissions to 90 percent below 1999 levels, and CO_2 emissions to 1990 levels. It was assumed that these emissions limits would be applied to all electricity generators, excluding cogenerators. This analysis examined the impacts of this set of limits on electricity-sector emissions of SO_2, NO_x, Hg, and CO_2 under four scenarios with different assumptions about technology cost and performance, energy policies, and consumer behavior.

Modeling Approach

The analyses for the House and Senate requests were prepared using NEMS. NEMS simulates the energy investment and utilization decisions of the various sectors of the U.S. economy including households, commercial establishments, industrial facilities, and energy suppliers. When power sector emission caps are imposed, NEMS simulates the decision process in each economic sector to determine an appropriate compliance strategy.

Each of the emission caps imposed was assumed to be implemented under a “cap and trade” system patterned after the SO_2 CAAA90 allowance program [*64*]. All electricity generators, excluding cogenerators, were assumed to be covered by the emissions caps. Electricity generators were assumed to behave competitively, incorporating the costs of emissions allowances in their electricity bid prices [*65*]. The cases included all energy laws and regulations in effect as of July 1, 2000, including the NO_x and SO_2 regulations established in the CAAA90, plus the new appliance efficiency standards announced in January 2001, as modified by the Bush Administration.

Uncertainties Related to Emissions Control Equipment

Considerable uncertainty exists about the ability of various types of emissions control equipment to remove Hg and, to a lesser extent, NO_x. Many factors affect the level of Hg emissions from a particular power plant, including the Hg content (by speciation—elemental Hg versus various Hg-containing compounds), chlorine content, and other chemical constituents of the coal used; the rank of the coal (i.e., bituminous or subbituminous); the boiler temperature and firing type and the flue gas temperature; and the types of existing control equipment for NO_x, SO_2, and particulates. In recent years data collection and analysis efforts have focused on these factors so that better estimates of current power sector Hg emissions could be developed; however, substantial uncertainty remains. As additional tests are performed, factors currently unaccounted for may turn out to be important.

The Hg removal rates for the various coal plant configurations also showed significant variation. The 1999 data show that, on average, a cold-side electrostatic precipitator (CSE)—a particulate removal device—removes 31 percent of the Hg that passes through it. However, the variation among plants with CSEs was large, ranging between 0 percent and 87 percent removal. The situation was similar for facilities with fabric filters—another type of particulate removal device. On average they removed 69 percent of the Hg passing through them, but, after excluding plants that actually reported increases in Hg after passing flue gas through the fabric filter, the removal rate ranged between 54 percent and nearly 100 percent.

In addition, there is very little information on the impact of new NO_x control devices—selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) equipment—on Hg emissions. Although many plant owners plan to add them in the near future, only a few are using them now. With respect to NO_x, SCRs are assumed to reduce emissions by 75 to 80 percent on average; however, because so few plants have SCRs today, the true cost and performance of the technology are not known at this time. With respect to Hg, this study assumes that, when combined with an SO_2 scrubber, an SCR enhances Hg removal with an emissions modification factor of 0.65 (increases Hg removal by 35 percent); however, no additional removal is assumed for plant configurations that have an SCR but do not have an SO_2 scrubber. Some pilot-scale tests suggest that SCRs would increase Hg removal for some system configurations, but the magnitude of the impact is not known at this time.

Analysis for House Request

The analysis cases examine the impacts of each emission cap and the RPS singly and in various combinations. The emission caps are applied only to the electricity generation sector, excluding cogenerators, and are assumed to cover emissions from both utility-owned and independent electric power plants. Cogenerators are treated as industrial facilities in this analysis. Because no requirements to reduce emissions in the residential, commercial, industrial, and transportation sectors are assumed, the results of this analysis are not directly comparable with the results of studies that have examined the impacts of complying with the Kyoto Protocol across all sectors of the economy.

In all cases it is assumed that emission caps for NO_x, SO_2, and CO_2 would be phased in beginning in 2002 and fully implemented by 2008. The cap on Hg emissions is assumed to begin in the compliance year (2008). For the cases that require that CO_2 emissions to average 7 percent below the 1990 level over the 2008 to 2012 period, the cap is constructed so that emissions are slightly above the 1990-7% level in the first year or two of the period and slightly below it in the later years. After 2012, the cap is held at 7 percent below the 1990 level through the remainder of the projections. In addition, it is assumed that the emission reduction programs will be operated as market-based emission cap and trade programs patterned after the SO_2 allowance program, and the emission allowance prices are included in the operating costs of plants that produce one or more of the emissions.

In many parts of the country the methodology used to price electricity—especially in the wholesale market—is currently changing. Historically, power prices have been based on embedded costs. In other words, all the costs associated with building and operating electric power plants were summed and divided by expected sales to determine the price per kilowatthour. As the generation market becomes more competitive, however, power prices are increasingly being set by the costs of the most expensive generator operating at any point in time—what economists refer to as the "marginal cost." This change could have significant impacts on the way in which emission allowance prices affect electricity prices and the resource costs of meeting the emission caps.

In competitive markets, allowance prices would become part of the operating costs of any generator producing the covered emission. Allowances are assumed to be given to generators at zero cost initially. After the initial allocation, however, additional allowances would have to be purchased in the marketplace. The allowance costs for the marginal generator are assumed to be included in the price of electricity in competitive markets.

Allowance prices may have a different impact on electricity prices in regulated markets, where prices are set according to cost of service. For example, if a company in a regulated region were allocated allowances at no cost, the regulatory authority would not include allowance prices when setting retail electricity prices. Conversely, if the regulated utility purchased allowances—from the government or from another utility—the cost of the allowances would likely be reflected in retail electricity prices. In the integrated cost of service CO_2 1990-7% 2008 case, it is assumed that allocated allowances will have zero cost in regions that have not deregulated. While this would lead to lower price impacts, the resource costs are likely to be higher, because consumers will not have the same incentive to reduce electricity consumption.

Recognizing the impact of natural gas supply and demand on electricity markets, an integrated high gas price CO_2 1990-7% 2008 case assumes that technologies associated with the finding, developing, and delivery of natural gas will not improve as rapidly as expected, and that additional Alaskan production and imports of liquefied natural gas projected in other cases with a CO_2 cap will not occur, resulting in higher natural gas prices.

Electricity Market Impacts in the House Analysis

When emission caps on NO_x, SO_2, CO_2, and Hg are assumed in various combinations, with and without an RPS, there are complex interactions among the compliance strategies and the resulting prices of emissions allowances and electricity prices (Table 3). When an RPS is assumed to be combined with NO_x, SO_2, CO_2, and Hg emissions caps, resource costs for generators complying with the caps are projected to be higher than when the RPS is not included. Although electricity prices are projected to be well above reference case levels when NO_x, SO_2, CO_2, and

Table 3. Key results for the electricity generation sector in the House analysis, 2010 and 2020

Projection	Reference case	CO_2 emissions capped at 1990 level: Without RPS	CO_2 emissions capped at 1990 level: With RPS	CO_2 emissions capped at 1990-7% level: Without RPS	CO_2 emissions capped at 1990-7% level: With RPS	Sensitivity cases[a]: Cost of service	Sensitivity cases[a]: High gas price
				2010			
Generation by fuel, excluding cogenerators (billion kilowatthours)							
Coal	2,245	1,290	1,425	1,069	1,223	1,003	1,079
Natural gas	825	1,421	1,026	1,575	1,189	1,740	1,525
Renewable fuels	397	484	723	503	706	515	514
Nuclear	725	741	741	741	741	744	744
Emissions allowance prices							
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	84	84	120	124	117	125
NO_x (1999 dollars per ton)[b]	NA	0	0	0	0	0	0
SO_2 (1999 dollars per ton)	187	1	3	0	2	0	0
Hg (million 1999 dollars per ton)	NA	443	432	296	342	308	305
Electricity price (1999 cents per kilowatthour)	6.1	7.9	8.0	8.4	8.6	7.7	8.6
Electricity sales (billion kilowatthours)	4,147	3,896	3,882	3,851	3,830	3,956	3,838
Electricity industry revenue (billion 1999 dollars)	255	308	311	324	329	304	330
				2020			
Generation by fuel, excluding cogenerators (billion kilowatthours)							
Coal	2,315	1,082	1,345	988	1,190	852	1,038
Natural gas	1,495	2,014	1,206	2,005	1,304	2,243	1,503
Renewable fuels	400	513	1,131	554	1,128	657	687
Nuclear	613	681	651	681	665	694	704
Emissions allowance prices							
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	135	71	150	90	162	169
NO_x (1999 dollars per ton)[b]	NA	0	1,304	0	1,118	0	0
SO_2 (1999 dollars per ton)	241	2	150	1	0	0	2
Hg (million 1999 dollars per ton)	NA	297	407	219	337	244	344
Electricity price (1999 cents per kilowatthour)	6.2	8.4	7.8	8.6	8.0	7.9	9.3
Electricity sales (billion kilowatthours)	4,788	4,309	4,354	4,257	4,313	4,453	4,188
Electricity industry revenue (billion 1999 dollars)	297	360	340	364	344	350	388
Cumulative resource costs, 2001-2020: difference from reference case (billion 1999 dollars)	NA	132	192	194	215	291	323

[a]The sensitivity cases shown require CO_2 emissions to be reduced to 7 percent below the 1990 level. They do not include a renewable portfolio standard.
[b]Regional NO_x limits are included, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
NA = not applicable.

Hg emissions are capped either with or without an RPS, they are projected to be lower in the long term when the RPS is included [*66*], because increased dependence on renewable technologies rather than natural gas would lead to lower prices for natural gas and for CO_2 allowances, offsetting the effects of the higher costs of renewable fuels on consumer electricity prices [*67*]. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as "producer surplus") to consumers (increasing "consumer surplus") even though the producers' resource costs are higher.

When power sector CO_2 emissions caps are assumed, at the 1990 level or 7 percent lower, the effects of efforts to comply with the CO_2 caps far outweigh the effects of steps that would be taken to comply with the other emission caps. As in the case of a CO_2 cap alone, the primary compliance strategy is expected to be a major shift in the fuel mix used to produce electricity. Power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewable fuels. In addition, fewer nuclear plants are projected to be retired, consumers are expected to reduce electricity use in response to higher electricity prices, and cogeneration capacity is expected to be expanded in response to higher grid-based electricity prices. The role of renewable technologies is especially important when an RPS requirement is included.

When CO_2 emissions are capped at the 1990 level, coal-fired electricity generation in 2020 is projected to be approximately half the level projected in the reference case, and the projected share of electricity generation from natural gas is much larger. When an RPS is included, the expected increase in renewable electricity generation dampens the increase in natural-gas-fired generation and slightly reduces the need to limit coal-fired generation. The addition of carbon-free renewable technologies stimulated by the RPS lowers the need to reduce coal use to meet the CO_2 cap. In contrast, when the cap on CO_2 emissions is tightened to 7 percent below the 1990 level, the projected reduction in coal-fired generation is even larger.

The combination of higher natural gas prices and CO_2 allowance prices is projected to lead to significant electricity price increases when a CO_2 cap is incorporated with other emission caps. As might be expected, when the CO_2 cap is set to 7 percent below the 1990 level, the projected impact on electricity prices is larger than when the CO_2 cap is set to the 1990 level. For example, the price of electricity in 2010 is projected to be 7.9 cents per kilowatthour when NO_x, SO_2, and Hg caps are combined with a CO_2 cap set to the 1990 level, but 8.4 cents per kilowatthour when they are combined with a cap set to 7 percent below the 1990 level—29 percent and 37 percent higher, respectively, than in the reference case. The higher electricity prices are projected to lead to increases of $146 and $192, respectively, in annual household electricity bills and $53 billion and $69 billion, respectively, in the Nation's total electricity bill.

When an RPS is included, the cumulative resource costs of compliance are projected to be $21 billion higher than they would be without the RPS with the CO_2 cap at 7 percent below the 1990 level. Electricity prices are projected to be higher in the early years of the forecast, when new renewable power plants are built rather than new natural-gas-fired plants. In the later years, however, the increased use of renewable fuels reduces natural gas consumption in the power sector, leading to a smaller projected increase in natural gas prices and lower CO_2 allowance prices and, in turn, a smaller increase in electricity prices.

Smaller increases in electricity prices are also projected when it is assumed that prices in many regions of the country will continue to be based on cost of service pricing. Regulators in those regions could treat any emissions allowances allocated to the companies they regulate as having zero cost, so that they would not be added to the operating costs of electric power plants. With this assumption, the price of electricity in 2010 is projected to be 9 percent less than when the wholesale power market is assumed to behave competitively—still 25 percent higher than without the stringent emission caps. However, power suppliers would have to take additional actions to reduce emissions, because consumers would not be expected to reduce their electricity usage as much as they would if electricity prices reflected the full opportunity costs of emissions allowances. As a result, supplier resource costs would be higher.

Electricity prices could be substantially higher if natural gas prices turn out to be higher than expected. When the reference case technology assumptions for natural gas discovery and production are replaced with assumptions of less robust technology development, the projected price of electricity in 2020 with combined NO_x, SO_2, Hg, and CO_2 emission caps is 9.3 cents per kilowatthour, 49 percent above the reference case projection and 8 percent above the corresponding projection based on reference case natural gas technology assumptions. The higher natural gas prices would also lead to greater reliance on renewable fuels and more conservation by consumers. Of course, these same natural gas technology assumptions would lead to higher natural gas prices in the reference case, even without the imposition of new emissions caps.

Fuel Market Impacts in the House Analysis

Imposing a CO_2 emission cap, whether at the 1990 level or 7 percent below the 1990 level and with or without stringent NO_x, SO_2, and Hg emission caps, is expected to have a dramatic impact on coal use in the power sector. Because the carbon content of coal is the highest among the fossil fuels, power suppliers are expected to reduce their coal use to meet a CO_2 emission cap. For example, when a CO_2 cap set to 7 percent below the 1990 level is assumed, coal consumption for electricity generation in 2020 is expected to be 59 percent below the reference case level.

Reducing NO_x, SO_2, and Hg emissions is not projected to have large impacts on natural gas markets—generally increasing its use in the power sector by a small amount. More significant impacts are expected when Hg emissions are capped at 5 tons than when either an NO_x or SO_2 emission cap is assumed. For example, when Hg emissions are capped at 5 tons, electricity sector natural gas consumption is projected to be 0.8 trillion cubic feet (11 percent) higher in 2010 than in the reference case.

The impact on natural gas markets of capping power sector CO_2 emissions is projected to be much larger than the impacts of other emission caps. Power suppliers are expected to turn to natural gas if they are required to reduce CO_2 emissions. For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x, SO_2, and Hg, electricity sector natural gas consumption is projected to be 10.6 trillion cubic feet in 2010 and 13.4 trillion cubic feet in 2020, as compared with 6.8 trillion cubic feet and 11.2 trillion cubic feet projected for 2010 and 2020 in the reference case. The one exception is when a 20-percent RPS is included with the emission caps. In this case, the projected increase in generation from nonhydroelectric renewable fuels partially reduces the need to turn to natural gas.

To meet the increased demand for natural gas when CO_2 emission caps are assumed, both domestic production and imports of natural gas are expected to grow. Total U.S. gas supplies are projected to reach 38.5 trillion cubic feet in 2020 if stringent caps are placed on power sector NO_x, SO_2, Hg, and CO_2 emissions, approximately 3.2 trillion cubic feet above the reference case projection. Of the 3.2 trillion cubic feet projected to be added, 0.8 trillion cubic feet is expected to come from domestic resources and 2.3 trillion cubic feet from higher imports. The annual increases in production required between 2005 and 2010 would be near record levels, representing a serious challenge for the industry.

The projected increase in natural gas use for electricity generation when a cap on power sector CO_2 emissions is assumed is expected to lead to higher natural gas prices. For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x, SO_2, and Hg, the natural gas wellhead price is projected to be \$3.66 per thousand cubic feet in 2010 and \$3.74 per thousand cubic feet in 2020, as compared with \$2.87 and \$3.22 per thousand cubic feet in the reference case.

Renewable Fuels Market Impacts in the House Analysis

When stringent caps on power sector NO_x, SO_2, and Hg emissions are assumed either one at a time or together, the projected impact on renewable fuel use for electricity generation is small. Because natural gas plants emit virtually no SO_2 or Hg emissions and very low NO_x emissions, they are expected to remain the most economical option when new electric power plants are needed. As a result, few new renewable power plants are projected to be built in response to stringent NO_x, SO_2, or Hg emissions caps.

Imposing a CO_2 emission cap on the power sector (especially one set to 7 percent below the 1990 level) is projected to have a significant impact on the development of renewable generating facilities. Although the primary compliance option for meeting a power sector CO_2 emission cap is expected to be increasing generation from natural-gas-fired power plants, the use of renewable fuels is also expected to grow, whether the CO_2 cap is assumed to be imposed alone or in concert with stringent caps on NO_x, SO_2, and Hg. The combination of higher natural gas prices as electricity suppliers consume more natural gas and the cost of CO_2 allowances begins to make new renewable plants economical.

For example, when a CO_2 cap of 7 percent below the 1990 level is assumed, nonhydroelectric renewable technologies are projected to provide 6.4 percent of U.S. electricity sales in 2020, up from 2.0 percent in

2000 and more than double the reference case projection of 2.8 percent in 2020. The key renewable energy technologies stimulated by a CO_2 cap are expected to be biomass (co-fired in coal plants and used in dedicated plants) and wind.

An RPS reaching 20 percent by 2020 is projected to have a larger impact on the use of renewable fuels for electricity generation than are power sector emissions caps on NO_x, SO_2, Hg, and/or CO_2. In general, meeting emissions reduction requirements by adding emissions control equipment and/or changing the mix of fossil fuels used for power production is projected to remain less costly than switching to more expensive renewable alternatives in the absence of an RPS. The renewable technologies expected to be stimulated by a 20-percent RPS are biomass, wind, and geothermal technologies. By 2020 the generation from qualifying nonhydroelectric renewable technologies is projected to reach 932 billion kilowatthours when a 20-percent RPS is assumed, as compared with 135 billion kilowatthours projected in 2020 in the reference case without an RPS.

Macroeconomic Impacts in the House Analysis

When stringent caps on power sector NO_x, SO_2, Hg, and CO_2 emissions are assumed, higher prices for electricity and natural gas are projected to have an impact on the U.S. economy. Higher energy prices would stimulate consumers to reduce their energy use and industries to shift to less energy-intensive production processes and products. The impact would be largest in the short term, when the economy first reacts to the higher prices. In the long run the economy is projected to recover and return to a more stable growth path.

When the four emission caps are first phased in, the unemployment rate is projected to be as much as 0.4 percentage points higher and real gross domestic product (GDP) as much as much as 0.9 percentage points lower in 2010 than projected in the reference case. By 2020, as the economy adjusts to the higher prices, real GDP is projected to be only 0.1 percent below the reference case level, and the unemployment rate is projected to be near the reference case level.

If, rather than a no-cost allocation of emission allowances, allowances were auctioned by the Federal Government, the economic impact could be different. The key question is what the Federal Government would do with the funds raised in the auction. If funds were returned to power suppliers, the effect would be the same as that of the no-cost allocation. If, on the other hand, they were given back to consumers in a lump-sum payment or through a cut in personal income taxes, the effect would be to help consumers maintain their level of overall consumption but reduce total investment. In the near term, this would be expected to reduce the impact on the economy, with GDP in 2010 projected to be 0.8 percent lower than in the reference case, as compared with 0.9 percent lower GDP with a no-cost allocation. In the longer term, the opposite would be the case: 0.4 percent lower GDP in 2020, as compared with 0.1 percent lower under the no-cost allocation scheme.

Analysis for Senators Smith, Voinovich, and Brownback (SVB)

In a second study, requested by Senators Smith, Voinovich, and Brownback, EIA examined the costs of different multi-emissions reduction targets. EIA was asked to analyze the impacts of three cases with alternative power sector emission caps on NO_x, SO_2, and Hg. The Senators also requested an analysis of the potential costs of requiring power suppliers to acquire offsets for any increase in CO_2 emissions that occur beyond the level expected in 2008.

Specifically, EIA was asked to analyze three cases for reducing power sector emissions with and without holding CO_2 emissions to 2008 reference case levels. The first case reduces NO_x emissions by 75 percent below 1997 levels, SO_2 emissions 75 percent below full implementation of CAAA90 Title IV, and Hg emissions by 75 percent below 1999 levels. In the two other cases the reductions are less—65 percent and 50 percent, respectively.

The emission reduction programs are assumed to cover all electricity generators other than cogenerators [*68*] and to operate as cap and trade programs patterned after the SO_2 control program created in the CAAA90. It was requested that the analysis should assume that the programs would begin in 2002, achieving half the required reductions by 2007 and full compliance by 2012. At the request of the Senators, the existing summer season NO_x cap and trade program is assumed to be replaced by the annual programs established in each of the cases. For Hg, half the required reductions are to come from actual reductions at each unit, and the rest can be achieved through allowance trading among units.

In all cases, power suppliers are able to bank emissions for future use. In other words, power suppliers can chose to reduce their emissions below the number of allowances they have in some years and hold (bank) them for use in other years. Typically a power supplier would be expected to do this in the early phase of the emission reduction programs, when allowances are relatively inexpensive, so that they can reduce the number of allowances they might have to buy in the later phases, when allowances might be more expensive.

Electricity Market Impacts in the SVB Analysis

The key results of controlling NO_x, SO_2 and Hg emissions to the required levels include adding emissions control equipment as the dominant compliance option. Emission allowance costs and electricity prices are projected to increase as the caps on NO_x, SO_2, and Hg are tightened across the cases (Table 4). In 2020, the price of electricity is projected to be between 1 and 6 percent higher than in the reference case. The Nation's total electricity bill is projected to be 1 to 5 percent higher in 2020 (between \$3 and \$13 billion 1999 dollars), as compared with the reference case.

From 2001 to 2020, power supplier resource costs are projected to be between \$28 billion and \$89 billion higher than in the reference case. When it is assumed that power suppliers are required to purchase offsets for CO_2 emissions above the projected emissions level in 2008 in the reference case and that trading outside the power sector is not permitted, the CO_2 allowance price in 2020 is projected to range from \$33 per metric ton carbon equivalent in the 75-percent reduction case to \$54 per metric ton in the 50-percent reduction case (Table 5). The allowance price is higher in the 50-percent case than in the 75-percent case because more offsets are needed in the 50-percent case.

Fuel Market Impacts in the SVB Analysis

Decreased use of coal and increased use of natural gas in the electricity sector is projected when emission reductions at these levels are required. By 2020, coal-fired generation is projected to be between 4 and

Table 4. Key results for the electricity generation sector in the Smith-Voinovich-Brownback analysis without holding carbon dioxide emissions to 2008 levels, 2010 and 2020

Projection	Reference case[a]	50-percent reduction case	65-percent reduction case	75-percent reduction case
	2010			
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,238	2,162	2,064	2,068
Natural gas	826	903	989	984
Renewable fuels	396	399	401	401
Nuclear	720	725	725	729
Emissions allowance prices				
SO_2 (1999 dollars per ton)	180	210	415	296
NO_x (1999 dollars per ton)[b]	NA	1,208	1,491	2,072
Hg (million 1999 dollars per ton)	NA	29	40	64
Electricity price (1999 cents per kilowatthour)	6.1	6.1	6.2	6.2
Electricity sales (billion kilowatthours)	4,133	4,135	4,122	4,120
Electricity industry revenue (billion 1999 dollars)	253	253	257	257
	2020			
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,302	2,221	2,135	2,083
Natural gas	1,488	1,551	1,626	1,661
Renewable fuels	399	407	409	411
Nuclear	610	613	613	613
Emissions allowance prices				
SO_2 (1999 dollars per ton)	200	719	1,390	1,737
NO_x (1999 dollars per ton)[b]	NA	1,108	1,457	2,825
Hg (million 1999 dollars per ton)	NA	42	82	170
Electricity price (1999 cents per kilowatthour)	6.1	6.2	6.3	6.5
Electricity sales (billion kilowatthours)	4,763	4,749	4,736	4,716
Electricity industry revenue (billion 1999 dollars)	292	295	301	305
Cumulative resource costs, 2001-2020: difference from reference case (billion 1999 dollars)	NA	28	66	89

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.
[b]Regional NO_x limits are included in the reference case, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
NA = not applicable.

10 percent below reference case levels, and natural-gas-fired generation is projected to be between 4 and 10 percent higher than reference case levels.

The potential exists, however, for an increase in coal use and its associated emissions in other sectors of the economy (i.e., residential, commercial and industrial) not covered by emission cap programs. However, because coal plays such a small role in these sectors and because the projected reduction in coal prices is generally expected to be less than a few percent, the potential for emission "leakage" appears slight [*69*]. The increase in natural gas prices that is projected to occur because of increased use in the electricity sector appears to be more important, leading to lower overall fuel consumption and emissions in other sectors. Natural gas prices to all users in 2020 are projected to be $0.28 per million Btu higher in the 75-percent reduction case than in the reference case.

Analysis for Senators Jeffords and Lieberman (J/L)

For this analysis, Senators Jeffords and Lieberman requested that EIA consider the impacts of technology improvements and other market-based opportunities on the costs of emissions reductions from electricity generators. Using 2002 as a start date for emissions reductions, the request specifies that by 2007 NO_x emissions from electricity generators are to be reduced to 75 percent below 1997 levels, SO_2 emissions to 75 percent below the full implementation of the CAAA90 Phase II requirements, Hg emissions to 90 percent below 1999 levels, and CO_2 emissions to 1990 levels. These emissions limits are applied to all electricity generators, excluding cogenerators.

The impacts of emissions limits were analyzed using four cases with varying levels of energy demand and technology costs and different assumptions about energy policies: the reference case from the *Annual Energy Outlook 2001* (*AEO2001*), published in December 2000; an advanced technology case combining the high technology assumptions for end-use demand, supply, and generating technologies from *AEO2001*; and cases incorporating the moderate and advanced policies from *Scenarios for a Clean Energy Future* (*CEF*), a publication of an interlaboratory working group, published in November 2000 [*70*]. The policies in the *CEF* analysis included fiscal incentives, regulations, and increased research and development funding for advanced technologies. The advanced *CEF* case also included a domestic CO_2 trading system for all energy markets that was assumed to equilibrate at a permit value of $50 per metric ton carbon equivalent, which would be announced in 2002 and implemented in 2005.

Electricity Market Impacts in the J/L Analysis

The *AEO2001* reference case included continuing development of energy-consuming and producing technologies, consistent with historical trends in research and development funding. The advanced technology assumptions in *AEO2001* were based on more optimistic technology development throughout

Table 5. Key results for the electricity generation sector in the Smith-Voinovich-Brownback analysis holding carbon dioxide emissions to 2008 levels, 2020

Projection	Reference case[a]	50-percent reduction case	65-percent reduction case	75-percent reduction case
	2020			
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,302	1,894	1,842	1,794
Natural gas	1,488	1,653	1,767	1,816
Renewable fuels	399	468	438	442
Nuclear	610	637	631	631
Emissions allowance prices				
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	54	37	33
SO_2 (1999 dollars per ton)	200	527	2,009	2,812
NO_x (1999 dollars per ton)[b]	NA	0	931	432
Hg (million 1999 dollars per ton)	NA	15	53	98
Electricity price (1999 cents per kilowatthour)	6.1	7.1	7.0	7.1
Electricity sales (billion kilowatthours)	4,763	4,615	4,631	4,631
Electricity industry revenue (billion 1999 dollars)	292	328	324	329

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.

[b]Regional NO_x limits are included in the reference case, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.

NA = not applicable.

the energy system, consistent with more aggressive research and development programs. The costs to achieve these technology improvements were not quantified, because there is no analysis showing that funding levels for research and development can be tied directly to the successful development of new technologies.

The moderate and advanced cases in *CEF* included a number of policies to encourage the development and adoption of technologies that are more energy-efficient and with lower emissions. However, the success of these programs was based in part on assumed changes in consumer behavior that are not consistent with historical behavior patterns, research and development funding increases that have not occurred, and voluntary and information programs for which there is no analytical basis for evaluating the impacts. Also, some of the assumed *CEF* policies required legislative or regulatory actions that may not be enacted at all or may be enacted at later dates than assumed in *CEF*.

Future technology development cannot be known with certainty, and even the technology improvements assumed in the reference case are likely, but not certain. The more rapid technology development assumed in the advanced technology case and in the *CEF* cases is more uncertain and represents a higher level of risk for the ultimate success and timing of the technology improvement. Furthermore, the simultaneous success of a wide range of technology development projects is highly unlikely.

Because the reference case is based on historical levels of funding and technology development, the technology trends assumed in the reference case are considered to be the most likely trends. However, of the cases considered in this study, the reference case projects the highest costs for reducing emissions. Relative to the reference case, the advanced technology case and the cases with the *CEF* policies all reduce projected energy demand, energy prices, and related emissions. Total energy demand in 2020 is projected to be similar in the advanced technology case and the case incorporating the *CEF* moderate policies, with the lowest demand in the case incorporating the *CEF* advanced policies. Because the advanced technology case also includes more rapid technology development for fossil fuel supply, that case has the lowest projected energy prices. As a result of lower energy prices and demand, the advanced technology case and the *CEF* cases have lower projected energy expenditures than in the reference case.

Introducing the emissions limits in the reference case raises the projected average delivered price of electricity by 33 percent in 2020 relative to the reference case (Table 6). Electricity prices are higher because of the additional costs for emission control equipment, the costs of obtaining emissions permits, and higher fossil fuel prices to electricity generators. Overall, the higher electricity prices reduce the projected demand for electricity, although the impact is dampened by the higher projected natural gas price, which results from higher demand for natural gas. Coal-fired electricity generation is reduced with the imposition of the emissions limits, and due to the premature retirement of coal-fired generators, generation from natural gas, renewable, and existing nuclear technologies is higher, even with lower generation requirements. As a result of higher energy prices, energy expenditures are projected to be higher than in the reference case (without emissions limits).

The total cost of supplying electric power, which is called the resource cost, includes the cost of fuel, operations and maintenance costs, investments in plant and equipment, and costs of purchasing power. The resource cost does not include the costs of emissions allowances. Through 2020, the cumulative resource costs of electricity generation are projected to be $177 billion (undiscounted 1999 dollars), or 9 percent, higher with the emissions limits.

Imposing the emissions limits on the advanced technology case raises the projected average delivered price of electricity by 22 percent in 2020, less than the increase in the reference case. Lower projected demand for electricity and the use of less carbon-intensive fuels in the advanced technology case relative to the reference case reduce the effort needed to meet the emissions limits. Among the four emissions that have limits in these cases, CO_2 emissions tend to be the most costly to reduce, largely through the premature retirement of existing coal plants and increased use of natural gas and renewable technologies. CO_2 sequestration is included in NEMS, but currently there are no economical technologies to sequester CO_2 emissions from generation plants, unlike the technologies available for the removal of the three other emissions.

Because the advanced technology case without limits has lower CO_2 emissions than the reference case, fewer shifts in electricity generation are required to meet the CO_2 limits when they are imposed. In addition, because reductions in CO_2 emissions also reduce SO_2 and Hg emissions, it is less costly to achieve reductions of these emissions in the advanced technology case than in the reference case. Additional investments in emissions control equipment are required to meet the limits. NO_x allowance prices are projected to decline to zero in the advanced technology case with emissions limits.

When the emissions limits are imposed in the advanced technology case, the higher electricity prices reduce the projected demand for electricity, but the reduction is less than projected in the reference case when the emissions limits are imposed, because the projected demand for electricity is already lower in the advanced technology case even without the limits, and because the projected increase in the electricity price is less than in the reference case. Similar trends in the generation mix are expected, although the magnitudes of the changes differ as the result of lower generation requirements and the higher level of renewable and nuclear generation in the advanced technology case without emissions limits.

Similar to the reference case, demand for natural gas is expected to be higher when emissions limits are imposed in the advanced technology case, due to fuel switching by electricity generators and increased cogeneration in the commercial and industrial sectors. Higher projected prices result in higher energy expenditures in the advanced technology case when the limits are imposed. From 2001 through 2020, the incremental cumulative resource costs of complying

Table 6. Key results for the electricity generation sector in the Jeffords-Lieberman analysis, reference and advanced technology cases, 2010 and 2020

Projection	Reference case without emissions limits[a]	Reference case with emissions limits[a]	Advanced technology case without emissions limits	Advanced technology case with emissions limits
	2010			
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,238	1,276	2,240	1,324
Natural gas	826	1,395	719	1,292
Renewable fuels	396	492	402	515
Nuclear	720	741	744	744
Emissions allowance prices				
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	93	NA	69
SO_2 (1999 dollars per ton)	180	46	168	152
NO_x (1999 dollars per ton)[b]	NA	0	NA	0
Hg (million 1999 dollars per ton)	NA	482	NA	510
Electricity price (1999 cents per kilowatthour)	6.1	8.0	5.9	7.4
Electricity sales (billion kilowatthours)	4,133	3,872	4,049	3,835
Electricity industry revenue (billion 1999 dollars)	252	310	239	284
	2020			
Generation by fuel, excluding cogenerators (billion kilowatthours)				
Coal	2,302	1,041	2,246	1,146
Natural gas	1,488	2,072	1,331	1,911
Renewable fuels	399	519	409	524
Nuclear	610	669	672	720
Emissions allowance prices				
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	122	NA	58
SO_2 (1999 dollars per ton)	200	221	145	703
NO_x (1999 dollars per ton)[b]	NA	0	NA	0
Hg (million 1999 dollars per ton)	NA	306	NA	374
Electricity price (1999 cents per kilowatthour)	6.1	8.1	5.5	6.7
Electricity sales (billion kilowatthours)	4,763	4,320	4,610	4,294
Electricity industry revenue (billion 1999 dollars)	291	350	254	288
Cumulative resource costs, 2001-2020: difference from corresponding case without emissions limits (billion 1999 dollars)	NA	177	NA	142

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.
[b]Regional NO_x limits are included, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
NA = not applicable.

with the emissions limits in the advanced technology case are projected to be $142 billion (an 8-percent increase), compared with $177 billion (a 9-percent increase) in the reference case.

In the *CEF-JL* moderate case, average delivered electricity prices are expected to be higher in 2020 when emissions limits are imposed (7.2 cents per kilowatthour compared with 6.0 cents per kilowatt-hour) because of the cost of allowance permits and emissions control equipment (Table 7). As a result of higher electricity prices, total projected electricity consumption in 2020 is reduced. However, electricity demand and prices are essentially unchanged in the advanced case with the addition of the emissions limits, because a $50 per ton carbon allowance price is assumed even without emissions limits.

In the *CEF-JL* advanced case with emissions limits, the CO_2 allowance price is essentially the same as in the advanced case without the limits, which assumes a $50 CO_2 allowance price across all energy markets. The projected costs for NO_x permits decrease to zero by 2020 in the *CEF-JL* advanced case as the actions taken to reduce CO_2 emissions result in NO_x emissions within the limits.

Between 2001 and 2020, the cumulative incremental resource costs to electricity generators to comply with the emissions limits are projected to be $162

Table 7. Key results for the electricity generation sector in the Jeffords-Lieberman analysis, CEF-JL moderate and advanced technology cases, 2010 and 2020

Projection	Reference case without emissions limits[a]	Moderate case without emissions limits	Moderate case with emissions limits	Advanced case without emissions limits	Advanced case with emissions limits
			2010		
Generation by fuel, excluding cogenerators (billion kilowatthours)					
Coal	2,238	2,221	1,357	1,737	1,395
Natural gas	826	616	1,138	800	1,090
Renewable fuels	396	406	543	555	578
Nuclear	720	720	741	735	735
Emissions allowance prices					
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	NA	64	50	54
SO_2 (1999 dollars per ton)	180	169	316	102	130
NO_x (1999 dollars per ton)[b]	NA	NA	0	NA	0
Hg (million 1999 dollars per ton)	NA	NA	549	NA	481
Electricity price (1999 cents per kilowatthour)	6.1	5.8	7.1	6.5	6.7
Electricity sales (billion kilowatthours)	4,133	3,920	3,747	3,777	3,745
Electricity industry revenue (billion 1999 dollars)	252	227	266	246	251
			2020		
Generation by fuel, excluding cogenerators (billion kilowatthours)					
Coal	2,302	2,296	1,284	1,567	1,276
Natural gas	1,488	908	1,330	1,181	1,416
Renewable fuels	399	413	624	551	561
Nuclear	610	595	646	575	617
Emissions allowance prices					
CO_2 (1999 dollars per metric ton carbon equivalent)	NA	NA	68	50	50
SO_2 (1999 dollars per ton)	200	184	905	707	670
NO_x (1999 dollars per ton)[b]	NA	NA	81	NA	0
Hg (million 1999 dollars per ton)	NA	NA	468	NA	391
Electricity price (1999 cents per kilowatthour)	6.1	6.0	7.2	6.6	6.6
Electricity sales (billion kilowatthours)	4,763	4,197	3,910	3,862	3,855
Electricity industry revenue (billion 1999 dollars)	291	252	282	255	254
Cumulative resource costs, 2001-2020: difference from corresponding case without emissions limits (billion 1999 dollars)	NA	NA	162	NA	129

[a]The reference case differs slightly from the reference case for the House analysis as a result of data revisions and model enhancements that were made after the House analysis had been completed.

[b]Regional NO_x limits are included, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.

NA = not applicable.

billion and $129 billion in the moderate and advanced cases, respectively—increases of 9 and 8 percent. The lower costs of compliance projected in the advanced case are due to the availability of more efficient generating technologies compared with the moderate case. In addition, because lower SO_2 emissions are assumed in the *CEF-JL* advanced case even without the emissions limits to simulate the impact of particulate controls, the addition of the emissions limits can be achieved at a lower relative cost.

Because the *CEF-JL* advanced case already includes a $50 CO_2 allowance price, there is little additional CO_2 reduction required, and energy expenditures are only slightly higher. In the *CEF-JL* moderate case with emissions limits, higher projected prices for coal, natural gas, and electricity are projected to reduce energy consumption in the residential and commercial sectors, compared to the case without limits, and to increase total energy expenditures. In the industrial sector, projected energy consumption in 2020 is essentially unchanged, because higher demand for natural gas for cogeneration offsets lower demand for purchased electricity.

In the electricity generation sector, projected coal-fired generation in 2020 is reduced in the moderate and advanced cases with the addition of the emissions limits. The impact is less in the advanced case, however, because the advanced case without the limits already includes a $50 CO_2 allowance price and a reduction in particulate emissions. Generation from natural gas, existing nuclear power plants, and renewable sources is projected to be higher in both cases when the emissions limits are imposed, because the limits raise the cost of coal-fired generation. Cogeneration of electricity is also higher in the commercial and industrial sectors in the *CEF-JL* moderate case when emissions limits are imposed. Total projected CO_2 emissions in 2020 are reduced by 12 percent and 4 percent in the *CEF-JL* moderate and advanced cases with emissions limits, respectively, compared to the cases without the limits, primarily due to lower levels of coal-fired generation.

Fuel Market Impacts in the J/L Analysis

In the four cases, demand for natural gas is increased by electricity generators that are subject to the emissions limits. Natural gas demand is also projected to be higher for commercial and industrial cogeneration in all cases except the case with the advanced *CEF* policies. This case is the exception because the $50 per ton CO_2 allowance price in the case without limits is essentially the same as the CO_2 allowance price that results when the emissions limits are imposed.

As a result of higher projected natural gas demand, natural gas prices are projected to be higher by between 11 and 20 percent in all four cases when the emissions limits are imposed. Because the *CEF* advanced policies include a $50 per ton CO_2 allowance price and a policy to reduce particulate emissions, coal consumption is sharply reduced in that case and electricity prices are higher relative to the reference case, even without the emissions limits, and imposing emissions limits does not cause a significant additional reduction in total energy demand in that case. Although the total energy expenditures are lower in the advanced technology and *CEF* cases than in the reference case, energy expenditures are expected to increase when the emissions limits are imposed in all cases, except the case incorporating the *CEF* advanced policies.

Macroeconomic Impacts in the J/L Analysis

The assumed emissions limits are expected to have measurable short-term impacts on the economy when the limits are fully imposed in 2007, with a reduction in gross domestic product ranging from 0.4 to 0.8 percent. The impact is significantly reduced, even by 2010, as the economy adjusts to higher energy prices. In all cases except the reference case, the macroeconomic impacts of the emissions limits are greatly reduced by 2020, with reductions in gross domestic product ranging from zero to 0.1 percent.

Summary of Results for Congressional Studies

It is useful to identify findings that are common across the three Congressional analyses of multiple emissions strategies. Generally, the costs of implementing multiple emissions strategies vary with the stringency of the reductions required and, to a lesser extent, the time frame for compliance. The higher the requirement to reduce CO_2 emissions and the shorter the time frame for the reductions, the higher the costs are expected to be. For example, when the emission reduction requirements are increased from 75 percent in the SVB analysis that excludes CO_2 limits to 90 percent in the J/L cases, which include CO_2 limits, the projected cumulative resource costs to achieve them increase from $89 billion to between $129 and $177 billion.

Higher resource costs and higher electricity prices to consumers are projected in all the multiple emissions cases analyzed. Electricity prices increase as a result of investments in emission control technologies, purchases of allowances, construction of new generating equipment to replace existing equipment, and higher fuel costs. The highest increase in projected electricity prices in 2020, 49 percent above the reference case level, is seen in the high gas price case in the House analysis, which assumes limits on CO_2 emissions as well as NO_x, SO_2, and Hg.

In all the analyses, higher electricity prices result in part from increases in natural gas consumption and the attendant high prices for natural gas in the emissions limits cases over the prices that would be expected without emissions limits. Natural gas consumption increases because it has lower emissions than other fossil fuels, particularly coal. Nuclear power and renewable energy sources also have lower emissions than either coal or natural gas. When emissions limits are assumed, the use of coal as a fuel for electricity generation is less desirable, and as a result consumption declines. In most of the cases that include caps on CO_2 emissions, coal-fired generation in 2020 declines to about one-half the level expected without CO_2 emissions limits. The expected decreases in coal-fired generation are much smaller when NO_x, SO_2, and Hg emission caps are assumed without the caps on CO_2 emissions.

A number of uncertainties are inherent in the multi-emissions analyses. For example:

- Although the *AEO2001* reference case incorporated improvements in technology cost and performance over time based on trends in historical data and consumer purchase decisions, it is difficult to assess the extent to which those trends might change in response to increased funding for research and development or expanded public information and voluntary participation programs.
- Although technologies for controlling SO_2 emissions are relatively mature, control technologies for NO_x, Hg, and CO_2 emissions are not as far along in the development cycle. The multi-emissions analysis cases assumed that new SCR technology would remove between 75 and 80 percent of NO_x emissions, but there has been little experience with actual operating facilities. Small changes in the cost and performance of emissions control technologies could have significant impacts.
- Even among power plants with similar equipment, there is substantial variation in the amount of Hg removed by NO_x and SO_2 control equipment.
- A number of policy instruments could be used in efforts to reduce emissions, with different implications for the impacts of emission reductions. A cap and trade program, as assumed in these analyses, is expected to lead to the lowest resource cost for compliance. Other options could lead to lower electricity price impacts but higher resource costs.

Finally, EIA has not performed any analyses of the benefits that may accrue from implementing multi-emissions control policies. The EPA is responsible for such analyses, and interested readers are referred to the EPA web site (www.epa.gov) for studies that have been carried out.

Modeling Energy Efficiency

Definition of Energy Efficiency

Energy efficiency and conservation are high-profile issues in the current debate about U.S. energy policy. Energy efficiency can mean different things to different people. Here it is defined as the ratio of energy service provided (output) to energy consumed (input) [*71*]. By this definition, gains in energy efficiency can be achieved either by using less energy input to provide the same level of energy service or by providing more energy service from the same level of energy input. Energy conservation is defined as a reduction in energy consumption through a reduction in energy service provided. "Pure" conservation measures leave the ratio of energy service to energy consumption unchanged and thus do not affect efficiency. How narrowly or broadly energy services are defined can affect whether a change is characterized as an efficiency gain or a conservation measure.

Measuring the energy efficiency of the U.S. economy is a daunting task, because data sufficiently disaggregated to permit isolation of the various end-use components of energy consumption and energy service generally are not available. For example, data on residential energy consumption per household can be constructed from utility records, but detailed end-use energy consumption and energy service data are not separately measured or collected, and data on energy use for residential space heating and the energy service (heat) provided are not available on an economy-wide basis. In lieu of energy efficiency measures, the description of the U.S. economy usually is framed in terms of "energy intensity" concepts, such as energy consumption per unit of real GDP or energy consumption per capita. Energy intensity is generally defined as energy consumption per unit of an indicator (such as economic activity or population) that provides a rough proxy for energy service supplied. Because of their aggregate nature and the use of proxies for energy services, energy intensities can be affected by a variety of structural factors unrelated to energy efficiency.

Because energy input (consumption) is included in the numerator, intensity measures are inversely related to efficiency measures. Thus, other factors being held constant, an increase in energy efficiency will reduce energy intensity. Changes in energy intensity can occur, however, without underlying changes in energy efficiency. Examples include conservation, structural shifts among sectors or regions of the economy, and changes in the mix of activities within sectors.

In contrast to the limited availability of information for measuring the historical performance of the economy, NEMS includes rich technology characterizations and end-use consumption detail, as well as explicit projections for energy services supplied. This detail provides the basis for developing estimates of projected energy efficiency. In NEMS, the effects of efficiency increases on projected energy consumption are modeled by incorporating economically based decision rules for end-use energy-using technology choices, coupled with sufficient options to allow the potential purchase of advanced, energy-efficient equipment, and by incorporating the effects of legislated mandates for efficiency improvements, such as corporate average fuel economy (CAFE) standards and equipment standards. The detailed NEMS projections have been used to develop an aggregate composite efficiency index (ACEI) based on more than 2,500 detailed subsector and end-use inputs.

Classification of Energy Efficiency Improvements

Residential space heating is an end-use energy service that is both familiar and sufficiently complex to illustrate important issues in the classification of energy efficiency improvements. For example, replacing an old, inefficient natural gas furnace with a new, more efficient one would be considered an efficiency increase by virtually anyone's definition. On the other hand, turning down the thermostat in the winter but doing nothing else would generally be considered a conservation measure.

Not all actions have such clear classifications. For example, installing attic insulation to reduce heating needs could be classified either as an efficiency gain or as a conservation measure, depending on how the "energy service" is defined. Because adding insulation, like turning down the thermostat, reduces energy use for heating, it could be classified as an energy conservation measure. On the other hand, if the concept of "interior warmth" is used to represent the heating energy service as a composite service provided by the combination of furnace equipment and insulation, then insulation allows the end user to maintain a given level of energy service (interior warmth) with a lower level of energy consumption, which meets the definition of a gain in energy efficiency.

Another home heating example is the installation of time-of-day thermostats. The energy-saving feature of a time-of-day thermostat is that when heat is not needed (for example, when the house is unoccupied or the occupants are sleeping), the temperature can be reduced so that less energy is consumed. This measure could be viewed either as a reduction in energy service (conservation) or as a more efficient way of providing the same level of energy service to the occupants of the home (efficiency increase). In NEMS it is classified as a conservation measure, because less energy service (whether noticed or unnoticed) is provided.

Passenger transportation in light-duty vehicles (cars, sport utility vehicles, pickup trucks, vans, minivans, and motorcycles) is another familiar energy service that can be used to illustrate the issues involved in defining and calculating energy efficiency. In the *AEO2002* reference case, the fuel efficiency (miles per gallon) of the light-duty vehicle fleet is projected to increase by an average of 0.3 percent annually between 2000 and 2020. Whether that is an appropriate estimate depends on how the energy service is defined.

Two components of the light-duty vehicle fleet, passenger cars and light trucks, account for 99.8 percent of its energy consumption. (Motorcycles are the remainder and can be ignored in this example.) For passenger cars, the average fuel efficiency of the fleet is projected to increase from 21.6 miles per gallon in 2000 to 24.6 miles per gallon in 2020, an average annual rate of 0.7 percent. For light trucks, average fuel efficiency is projected to increase from 17.1 miles per gallon to 18.2 miles per gallon, an average annual rate of 0.3 percent. At the same time, the mix of vehicles in the fleet is expected to shift in favor of the larger, less fuel-efficient light truck component (including sport utility vehicles). Light trucks accounted for 42 percent of total light-duty vehicle energy consumption in 2000, but in 2020 they are projected to account for 56 percent of the total. As a result, when the energy services provided by the two vehicle categories are considered to be the same, the projected shift to less efficient light trucks results in a projected overall increase in fleet efficiency averaging 0.3 percent per year.

The calculation of separate efficiency indexes for cars and light trucks assumes that consumers value the energy services received from light trucks differently from those received from passenger cars [*72*] and, therefore, that cars and light trucks should be considered as separate end-use categories. When this assumption is made, calculation of the projected rate of increase in energy efficiency for light-duty vehicles as a whole involves weighting the expected increases for the two components by their projected proportions of light-duty vehicle energy consumption. By this method, the calculated rate of efficiency improvement is 0.5 percent per year, significantly higher than the 0.3-percent average annual increase that is projected when all light-duty vehicles are considered as a single end-use category providing the same energy service.

Calculating the Aggregate Composite Efficiency Index

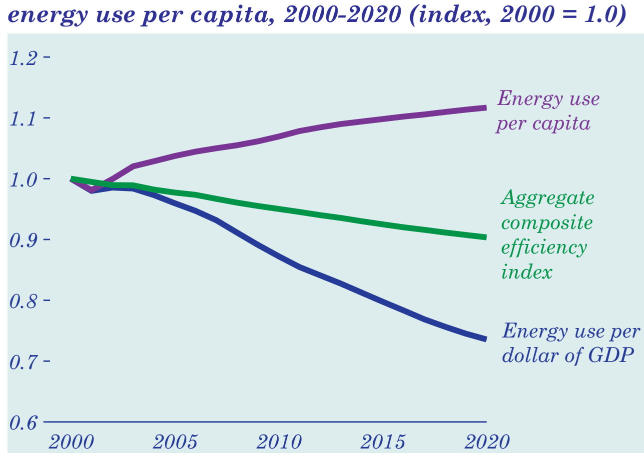
Energy consumption in the U.S. economy is fully accounted for by five broad sectors—residential, commercial, transportation, industrial, and electricity generation. NEMS energy projections include the effects of many factors in addition to efficiency changes, such as the energy consumption shares of the five sectors, the mix of industries producing industrial output, weather effects, short-run responses to changes in energy prices (elasticity effects), regional variations, housing unit size, and end-use penetration of energy-using technologies. In estimating energy efficiency, factors other than efficiency must be removed from the calculations, so that energy consumption unitized on the basis of service demand (e.g., adjusted energy consumption per square foot for buildings) can be used as a valid measure of end-use efficiency.

In the residential and commercial sectors, regional effects are an important consideration. For example, because the requirements for energy services for residential and commercial buildings are related to climate, a shift in population toward the South would be expected to increase the total U.S. demand for air conditioning. If regional effects were not taken into account, a population shift to warmer climates could be mistaken for a decrease in efficiency, because energy consumption per household for air conditioning would increase. Similarly, the energy service requirements for single-family homes differ from those for mobile homes, office buildings, or health care facilities. Thus, for efficiency calculations, energy services are tracked separately for the residential and commercial building types modeled in each of the nine Census divisions. The residential and commercial models include 3 and 11 building types, respectively, as well as 27 and 18 combinations of end-use service and fuel type, respectively [*73*]. For the transportation sector, energy services for 10 vehicle classifications are incorporated into the efficiency calculations. For the industrial sector, 13 industries are separately tracked. Electricity generation sector efficiency is modeled as sales to the end-use sectors divided by energy input.

Calculation of the ACEI involves what is in essence an energy-weighted average of the individual efficiency indexes. This procedure is similar to the indexing method used to construct the consumer price index (CPI) [*74*]. For comparability with intensity measures, the reciprocal of the ACEI is calculated. That is, an efficiency gain results in a decline in the ACEI, as it would for an intensity measure. The results are calculated for the five broad energy consumption sectors, as well as for the U.S. economy as a whole.

Figure 11 compares the ACEI with indexes of energy consumption per dollar of GDP and energy consumption per capita. The base year for all the indexes is 2000. The ACEI shown in Figure 11 is projected to improve (decline) steadily over time. The energy intensity of the economy is also projected to improve

Figure 11. Comparison of projections for the aggregate composite efficiency index, energy use per dollar of gross domestic product, and energy use per capita, 2000-2020 (index, 2000 = 1.0)



(decline) over time, whereas per capita energy intensity is expected to increase.

To illustrate the effects of the projected changes in the three indexes over the forecast period, Figure 12 compares the reference case projections of U.S. energy consumption with alternative projections derived by holding each of the indexes at its 2000 value. In the reference case, energy consumption is projected to increase at an average annual rate of 1.4 percent. If energy consumption per capita were projected to remain constant instead of increase, that growth rate would be reduced to 0.8 percent per year. In contrast, if there were no improvement in the energy intensity of the economy, or if energy efficiency did not increase, energy consumption would grow more rapidly than projected in the reference case. Assuming no change in the ACEI, energy consumption would be projected to grow at an average rate of 1.9 percent per year to 145 quadrillion Btu in 2020, 14 quadrillion Btu higher than the reference case projection of 131 quadrillion Btu. Assuming no change in the ratio of energy use to real GDP, energy consumption would be projected to grow at an average rate of 3.0 percent per year to 178 quadrillion Btu in 2020, 47 quadrillion Btu higher than the reference case projection.

The difference between the energy consumption projections in Figure 12 for the case assuming constant energy intensity of the economy and the case assuming constant energy efficiency as measured by the ACEI can be attributed to structural changes in the economy that are included in the ratio of energy use to real GDP but are removed from the efficiency calculations.

Figure 12. Projected primary energy consumption in the reference case and in alternative cases assuming no change in energy efficiency and energy intensity, 2000-2020 (quadrillion Btu)